MONITORING OF CO_2 SEQUESTRATION USING INTEGRATED GEOPHYSICAL AND RESERVOIR DATA

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ABSTRACT
Geophysical techniques provide the most cost-effective approach for obtaining the spatial coverage required for mapping the location and movement of CO_2 in the subsurface. However, the effectiveness of these techniques depends upon many factors, including the contrast between the physical properties of CO_2 and resident formation fluids, the lithology and structure of the reservoir, formation fluid pressures and pressure variations, source and receiver locations, well spacing and injection patterns. An iterative process of reservoir simulation and forward and inverse modeling can be used to access the effectiveness of candidate geophysical methods and to optimize monitoring systems. Results are presented for an example reservoir model of two sandstone reservoirs connected by a fault. Reservoir simulations provide a 3-D time-resolved grid of porosity, permeability, and gas-water-oil saturation, as well as injection and production. Forward calculations where made to predict the seismic, electromagnetic (EM) and gravity response. Through inversion the resolution of the techniques was assessed.

INTRODUCTION
Monitoring for geologic sequestration has been identified as one of the highest priority needs in several recent industry, academic, and government sponsored workshops (DOE 1998, MIT 1998). Monitoring will be necessary to quantify the net quantity of CO_2 that has been sequestered. It will be required for determining the efficiency with which available sequestration capacity has been utilized. It will be needed to optimize collateral economically beneficial processes, and finally, it will be necessary to ensure the safety by demonstrating that the CO_2 is retained in the formation into which it is injected.

Accommodating these diverse needs will require measurement of many different parameters and processes at many different locations and scales at the surface and in the subsurface. With the exception of the subsurface region between wells, technology is currently available for making most measurements. In the subsurface interwell region measurements must be made remotely and indirectly, raising issues of sensitivity and interpretation which need to be addressed.

The strategy for monitoring the subsurface interwell region will involve at least three elements. First is reservoir engineering. Reservoir simulations are needed to provide guidance on how the CO_2 will be distributed over time in the reservoir. The second element is geophysics, which will provide the most effective approach for obtaining the spatial coverage required for mapping the movement of CO_2 in the subsurface. However, the effectiveness of these techniques depends upon many factors, including the contrast between the physical properties of CO_2 and resident formation fluids, the lithology and structure of the reservoir, formation fluid pressures and pressure variations,

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source and receiver locations, well spacing and injection patterns. In addition, geophysical measurements only provide an indirect, non-unique indication of the presence of CO_2. The use of multiple techniques such as seismic and electromagnetic (EM) measurements, each of which is sensitive to different physical properties, is required to reduce ambiguity in interpretation of measurements. A firm basis for further development is provided by decades of experience in use of geophysics in the oil and gas industry. Relevant techniques include surface seismic, electrical and gravity measurements and higher resolution crosswell, single well and surface-to-borehole seismic, electromagnetic and electrical methods. What is needed is an assessment of the effect of the various factors mentioned above on the sensitivity and resolution of these techniques, and a methodology for selection of the optimum cost-effective combination of techniques.

The third element of the monitoring strategy is analysis and interpretation of data. Once again, leverage can be obtained from the oil and gas industry by building upon new techniques currently being developed to jointly invert data from different sources to obtain a best first image of reservoir properties.

SELECTION METHODOLOGY

Numerical simulation can be used to evaluate the sensitivity of candidate techniques and design optimum sensor configurations for a given site of interest. An iterative, three-step process is proposed. The first step is reservoir simulation. This is performed using the best available geologic model for the candidate site, incorporating the intended CO_2 injection strategy. Results of simulating the proposed CO_2 injection scenario provide fluid pressures, relative saturation, and distribution of the fluids in the reservoir.

The second step is to perform forward geophysical modelling on the same geologic model, integrating in the results of the reservoir simulation. This integration is carried out by converting reservoir parameters such as porosity and saturation to geophysical properties such as seismic velocity or electrical conductivity. Separate simulations are carried out for each candidate technique, such as seismic or electromagnetic. The result of the geophysical modeling is the response of the candidate geophysical method to the fluid distribution predicted by the reservoir simulation. Multiple realizations are performed to evaluate the optimum source/receiver configuration for a given technique.

The third step involves application of geophysical processing, analysis and inversion techniques to the results of the geophysical modeling. These are the same techniques that would be applied to geophysical data acquired in the field. At the conclusion of the third step decisions can be made about the geophysical method or combination of methods, and the optimum configuration of sources and receivers for a given monitoring application. Ultimately, numerical simulations must be validated through field tests.

NUMERICAL PLATFORM

The methodology described above involves linking together numerical simulators for reservoir processes, seismic, electrical, and gravity prediction, and inversion. Data from the reservoir simulator is passed to each of the geophysical simulators, and the output of these is passed to processing packages. The efficiency with which this data is transferred between simulators greatly impacts the practical applicability of the methodology.

A numerical platform has been developed to facilitate transfer of data between the various simulators. A general cell based 3D model is defined where each cell carries both hydrologic parameters (porosity, temperature, pressure, S_w, S_g, S_o) and geophysical parameters (compressional wave velocity, shear wave velocity, density, electrical resistivity). A graphical interface allows the user to build complex 3D regional models using surfaces defined from 3D seismic surveys or

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geologic mapping and well log data. Reservoir simulation parameters can be input to the regional, or background, model and converted to geophysical parameters using any user defined petrophysical model. The petrophysical models can be either empirically derived from log data or based on analytic models. The most important feature of such a platform is the ability to define a single self-consistent hydrologic and geophysical model that can be easily upscaled or downscaled to suit the needs of the various numerical simulations run from the platform. A researcher can easily study the change in geophysical response to changes in hydrologic parameters by graphically manipulating any parameter in any portion of the model in 3D. Once a change in parameter is made all dependent parameters are recalculated and new simulations are run with a single mouse click. This three-dimensional interactivity greatly increased the efficiency of modeling in 3D, allowing the investigation of the entire spectrum of complex 3D scenarios. This tool allows these investigation to occur in a timely fashion.

EXAMPLE ANALYSES

A model was constructed representing a typical depleted gas reservoir that might be considered as a candidate for CO_2 sequestration. A fault was placed in the model and following the methodology discussed above; the ability of seismic, gravity, and EM methods to detect the fault as a leakage pathway for CO_2, was evaluated.

The geologic model consists of a laterally extensive sand layer overlying a channel sand (permeability of 100 md and porosity of 0.1), shale (permeability of 1md and porosity of 0.2) separates the upper sand layer from the channel sand, but a high permeability vertical fault connects them. Figure 1a is a plan view of the lower channel sand showing the location of the fault and the curvilinear nature of the channel. Figure 1b is a cross-section through the model showing that the strata dips (at 10˚). The sands are separated by shale of the same thickness and shale is present above and below the sands.

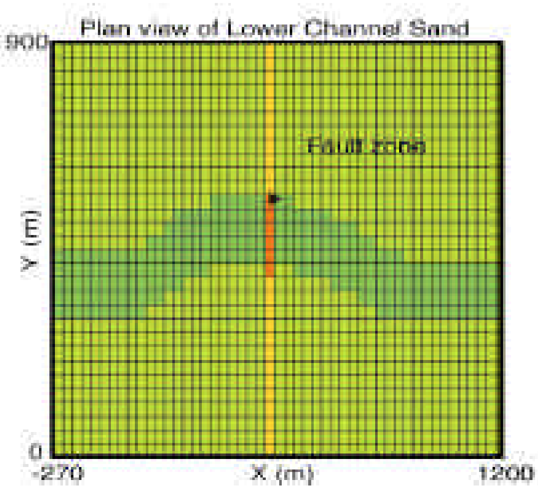

Figure (1a)

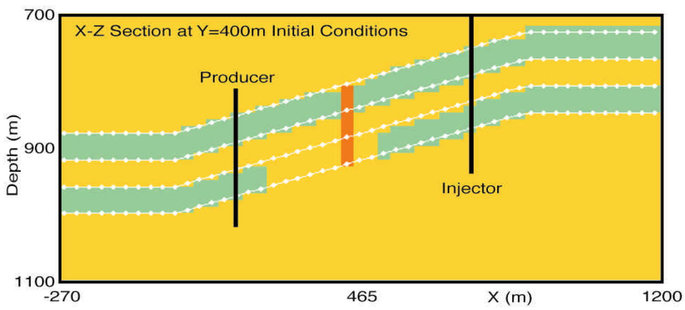

Figure (1b)

Figure 1: *Geologic model used for example analyses; (a) plan view of lower channel sand; (b) cross section*

Reservoir simulation was carried out using the Landmark multiphase fluid flow simulator. Injection of CO_2 into the lower channel sand was initiated at 5000 stb/day. Figure 2 shows the gas saturation in the central portion of the model 1000 days into injection. (For the pressure conditions in the model, the CO_2 remained in the gas phase). Green and blue shades show the region of elevated gas saturation due to the migration of the CO_2. The CO_2 moved along the channel sand, up the fault, and then moved up and downdip in the upper sand layer.

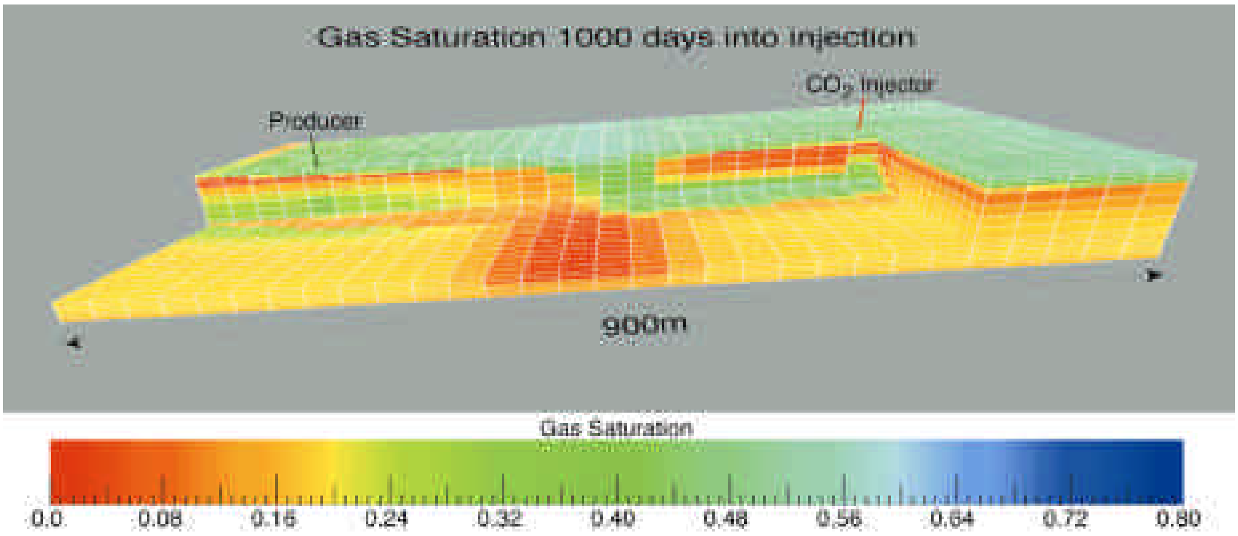

Figure 2: *Gas saturation given by reservoir simulation at 1000 days into* CO_2 *injection*

Geophysical forward simulations were carried out to determine if gravity, seismic and crosswell EM measurements, could detect the leakage of CO_2 through the fault. 3D gravity calculations were carried out on the same rectangular grid used for the finite difference EM calculations using the mbox algorithm (Blakely, 1995). The electromagnetic forward and inverse solutions were done using the 3D finite difference algorithms describe by Newman and Alumbaugh (1997). A crosswell EM configuration was simulated with a vertical magnetic dipole transmitters operating at 100 Hz placed in the "producer" well, while receivers measuring vertical magnetic field, were placed in the injection well. Surface and crosswell seismic experiments were simulated using the acoustic finite difference module within ProMax. Additional 2D and 3D fully elastic seismic simulations will be conducted in the future in order to access the use of shear waves in monitoring fluid migration.

Geophysical calculations were carried out in a time-lapse sense, i.e., first for initial conditions and then at 500 day increments until 2500 days into injection. Material property transforms were used to calculate the velocity, density and electrical resistivity from the reservoir porosity and gas, water and oil saturations. For gravity calculations this meant calculating changes in bulk density of the rock based on changes in gas saturation. For EM calculations the empirical relation developed by Archie (1942) was used to relate bulk resistance to porosity, pore fluid resistance, and water saturation. For seismic calculations compressional and shear wave velocities were calculated using a formulation of Dvorkin and Nur (1996) involving mechanical properties of the rock grains and the partial fluid saturations within the pores.

The final step was processing of the synthetic data, replicating procedures which would be carried out on actual field data. The calculated gravity data was equivalent to field data after all processing to remove regional trends leaving only the local anomalous field. Results are shown in Figure 3, which is a plan view of the change in the gravity field. It is seen that a 10% decrease in the vertical component was caused by the presence of CO_2 in the fault. The percent change decreases away from the fault.

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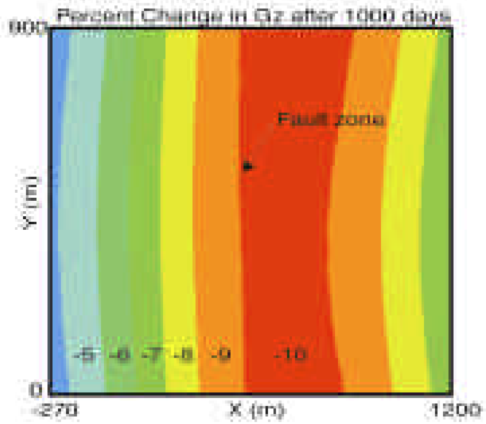

Figure 3: *Plan view of calculated change in gravity due to leakage of CO_2 into fault.*

Figure 4 shows migrated seismic sections of the fault zone for the initial model and after 1000 days of CO_2 injection. Superimposed in color is the acoustic impedance (AI), the product of velocity and density, derived from the material transforms. Increasing time on the vertical axis corresponds to increasing depth. In the initial model the fault zone is clearly shown as the lower AI (blue) region in the center of the image. The upper and lower sands are shown as the high impedance (red) layers at initial conditions. After 1000 days significant differences in the image show the effect of CO_2 and water migration in both sand units and in the fault zone. The largest AI decrease has taken place in the lower sand unit where CO_2 is being injected, but a significant decrease in AI has also occurred in the upper sand due to leakage through the fault.

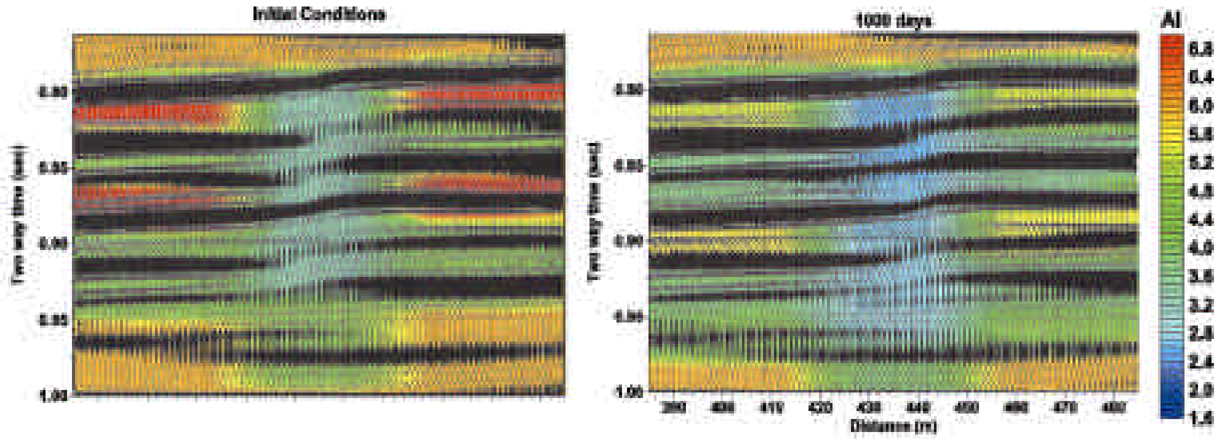

Figure 4: *Migrated seismic section for initial model and 1000 days into injection, overlain on acoustic impedance (AI) map. Increase in gas saturation due to CO_2 causes decrease in acoustic impedance.*

A crosswell seismic experiment was simulated in which sources and receivers were located in the depth interval 800 to 1100 m. Straight ray tomography was done starting from a uniform halfspace velocity model of 2200m/s. The lower layer, intermediate shale layer, and the fault zone were fairly well imaged, but the upper sand layer was not resolved due to the very limited apature of the source-receivers. This examples illustrates the utility of modeling as a design tool before errors in field measurements are made rendering the acquired data unfit for the required imaging task.

The simulated EM crosswell measurements at initial conditions and 1000 days into injection were inverted and differenced to produce the electrical conductivity difference image shown in Figure 5. This inversion code (Newman and Alumbaugh 1997) allows sharp boundaries, based on prior knowledge, to be placed in the starting model for the inversion. For the example case, the "prior

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knowledge" was the seismic data that showed the location of the fault. As shown in the figure, the EM inversion revealed a clear conductivity difference resulting from leakage of CO_2 and water through the fault.

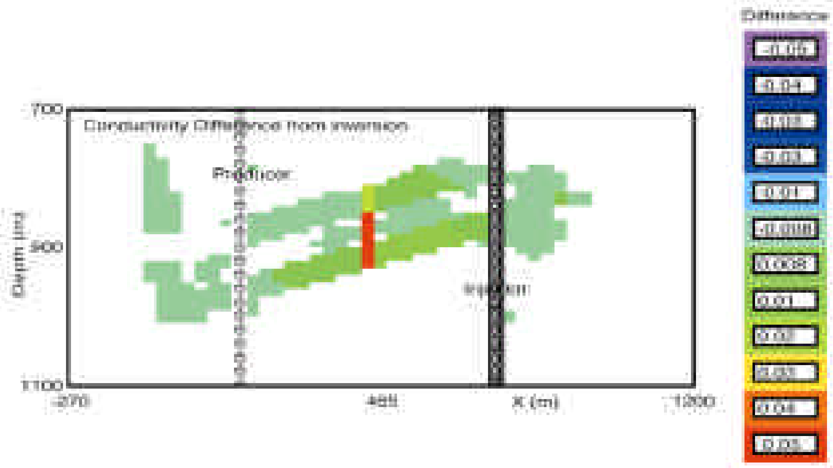

Figure 5: *Results of inversion of model generated crosswell EM measurements showing change in conductivity due to CO_2 movement.*

CONCLUSIONS

A methodology using reservoir simulation and forward and inverse geophysical modeling can be used to assess the effectiveness of candidate geophysical methods and to optimize monitoring systems. The methodology has been demonstrated using numerical models representing typical hydrocarbon reservoirs that might be candidates for CO_2 sequestration. Results for a case in which a fault provided a leakage path showed that combined gravity, seismic and crosswell EM geophysics could be used to detect such a fracture. Because of the large number of factors affecting geophysical measurements it is important to begin to apply this methodology in conjunction with measurement at site specific locations.

ACKNOWLEDGEMENTS

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